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Comments of Commonwealth Edison Company
On The Revised Draft Document To Be Submitted To The ICC Staff
"Evaluating The Potential Impact Of Transmission Constraints
On The Operation Of A Competitive Electricity Market In Illinois"

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Commonwealth Edison Company ("ComEd") appreciates the opportunity to comment on the revised draft form of a document to be submitted to the Illinois Commerce Commission (ICC) Staff by the University of Illinois and Argonne National Laboratories.

Undertaking the analysis of transmission systems in Illinois was a useful task and ComEd supported an early phase of the study by providing data to the authors. Unfortunately, because of budgetary issues beyond the control of Staff, the results of the analysis were delayed. This delay has resulted in much of the underlying data becoming stale and, in many cases, therefore being inaccurate. The draft document, based on NERC's November 2002 forecast of 2003, with some 2003 updates from utilities, was originally submitted to Staff in December 2003. The current version of the draft was revised in September 2004, a revision that expanded the analysis but did not update the data used in the 2003 draft because of resource constraints. The problem with stale transmission data is that transmission planning and operations are dynamic processes. Transmission planners continually review the system, and when system studies predict constraints they develop reinforcement plans in accord with system planning criteria. Thus, a model developed in 2002 with certain 2003 updates was a reasonably good starting point in 2003 – though even then, the predicted constraints would simply have been accommodated in future reinforcement plans. But a delay of several years has occurred, through no fault of Staff, and as a result the draft is now based on a model from which the Commission can draw no valid conclusions about constraints on the transmission system in 2007 and beyond.

In addition, when the project was initiated, the Illinois utilities were in the process of joining Regional Transmission Organizations (RTOs). Particularly during this transition, important features of both the operation of the system and the basic design and operation of the energy markets it supports have been in flux. By 2004 the major Illinois utilities had been integrated either into the PJM Interconnection (PJM) or the Midwest ISO (MISO), and in 2005 MISO implemented a regional market of the kind that PJM had long had. None of these developments could be taken account of in the draft document. The result is that the draft is even more seriously dated in the area of markets than in the transmission area. The change from the former independent control areas operated by the utilities to a regime in which an independent regional entity operates the utilities' systems and also operates regional markets, with market structures, market rules and market monitoring and mitigation, was a watershed in the history of the electric industry in Illinois. These changes are of such a magnitude that the draft, which does not take account of them, cannot serve as the basis for any valid conclusions about market concentration or market power. In particular, the conclusions that the draft t draws about the potential exercise of market power in northern Illinois result entirely from unrealistic assumptions inconsistent with the facts of the RTO markets. In sum, the draft's 's conclusions are inconsistent with the world that exists today and with a realistic forecast of tomorrow. While the goals set by the ICC are admirable, these facts will prevent the ICC from drawing any valid conclusions from the draft document.

A. The Draft Document's Market Analysis Is Fatally Flawed

The draft document does not purport to analyze and cannot draw conclusions concerning the realities of the existing market for electric power and energy and certain related ancillary services. ComEd is a fully integrated member of the PJM RTO and part of the largest organized power market in the world, with a market structure, market rules and a Market Monitoring Unit. The draft concedes that the PJM market is not included in its analysis. (Draft at 35.) Failure to take these real-world parameters into account results in erroneous theoretical constructs and conclusions. To reach valid market conclusions the authors of the draft would have to work with PJM (and with the MISO) to develop an up-to-date model with realistic assumptions.

The most striking conclusion of the draft is that under circumstances of transmission congestion that the authors find credible, generation owners in Illinois could exercise market power by withholding their generation from the market.

Physical Withholding: The draft concludes that physical withholding of a single generating unit on a peak day would only be highly profitable in the case of one Illinois coal unit, and withholding that unit would require dropping customer load. Withholding most other units would cause losses. (Table 4.2.1-1.) Under alternative, more reasonable, unit dispatch assumptions even withholding this unit was not found profitable. (Table 4.2.1-2.) The authors then tested withholding multiple units in various combinations to see whether this could be profitable. They tried withholding combinations of units based on the expected profitability of the units, and found that there was little or no profit in this type of withholding. (Draft Report at 114.) They tried withholding combinations of units based on the units' ability to drive down the system reserve margin (in the hope of increasing overall prices) and found that there was a clear profit benefit to companies in pursuing such a strategy. "In all cases," however, "the application of this strategy led to the need for load curtailments." (Draft at 116-17.) In addition, this profitability depended on the generating companies withholding the units only for selected hours. (Table 4.2.4-1.) As ComEd will show below, physical withholding of generating units in PJM is virtually impossible, and even if a unit were withheld it could not be withheld for only selected hours. Moreover, the authors did not consider the practical and legal consequences of such a strategy. Finally, it is absurd to assume that a generating company would deliberately cause customer load to be shed in an attempt to withhold generation from the market. (The authors acknowledge that "this situation is generally avoided by companies seeking to maintain good customer relations." Draft at 123.)

Economic Withholding: The draft concludes that effectively withholding a generating unit from the market by bidding it in at very high prices would not generate significant increases in profitability and would often have a negative impact. (Draft at 124, 163.) The authors then tested economically withholding a company's entire generation portfolio from the market. For Exelon Nuclear, they found that increasing the price of the fleet significantly for all hours on a peak day was not an attractive strategy. (Draft at 125, 163.) Bidding high prices for the entire fleet only during selected hours, however, they found to be significantly profitable. (*Id.*) One problem with this conclusion, as shown below, is that PJM market rules require that a unit be bid into the day-ahead market at an identical price in each of the 24 hours. Under alternative, more realistic, unit dispatch assumptions, the draft finds that this strategy would not improve Exelon Nuclear's profitability unless prices were raised by more than 20-fold. (Draft at 130, 163.)

Thus, on its own terms, the draft shows that physical or economic withholding of generating units could be profitable only under an unrealistic scenario such as dropping customer load in order to withhold the generation or withholding Exelon Nuclear's entire fleet from the market for selected hours. In addition, however, the authors make no attempt to assess whether any of the withholding strategies they have developed would be feasible or even possible under the real-world market structure and market rules of PJM. ComEd explains below why this invalidates even the limited conclusions that the draft draws.

- **The physical withholding the draft assumes is wholly unrealistic.**

The basic assumption of the draft about withholding is that "[g]enerating companies participating in a competitive electricity market may elect to take capacity off line in order to improve their business position." (Draft at 104.) This assumption is simply false in PJM. Under the PJM Operating Agreements, all network capacity resources – which include the Exelon Nuclear and Midwest Generation generating units – *must* be bid into the PJM day-ahead market each and every day for all 24 hours of the following day. Physical withholding, except for legitimate plant outage situations, is therefore a violation of PJM market rules. Whenever a generating unit is not bid into the market, the event is declared by PJM to be a forced outage. Each forced outage raises the forced outage rate of the unit and lowers the capacity payment the generator will subsequently receive from the capacity market. In addition, the PJM Market Monitoring Unit (MMU) would quickly evaluate whether the unit were in fact suffering from forced outage conditions. The oversight role of the MMU is described further below.

There are additional reasons why the assumption that Exelon Generation could withhold nuclear capacity from the market is erroneous. The Federal Energy Regulatory Commission (FERC) has repeatedly recognized that, as it said in a recent order approving a proposed Exelon merger, "the operational characteristics of, and [Nuclear Regulatory Commission] regulatory scrutiny over, nuclear units virtually eliminate the possibility of withholding output to drive up price." *Exelon Corporation and Public Service Enterprise*

Corporation, 112 FERC ¶ 61,011 (2005); *see USGen New England*, 109 FERC ¶ 61,291 (2001); *Commonwealth Edison Co.*, 91 FERC ¶ 61,036 (2000).

The FERC's findings are soundly based. It is safer and more economically efficient for a nuclear plant to run at a constant power level, preferably at full power. Exelon Nuclear's objective is to run its nuclear units as close to 100% capacity as it can, consistent with maintenance work and equipment surveillance. There are nuclear physics constraints, regulatory restrictions and economic disincentives to changing the power level of a nuclear reactor too frequently. When power output is reduced, the physics of the reactor core requires a waiting time for restoration of equilibrium that prevents a plant from responding quickly to shifts in demand. In addition, a nuclear plant must be operated within the Technical Specifications in its NRC license. Frequent changes in output could result in conditions that violate the license. Such fluctuations unnecessarily stress the mechanical and electrical components of a plant and present added challenges to the reactor operators. Furthermore, unlike fossil plants, a nuclear plant inserts all required fuel for an operating cycle during a refueling outage. For a strategy of changing power output, the required fuel content is uncertain, and such a strategy can lead to uneconomical fuel design and utilization, resulting in an economic penalty to the operating utility. For all these reasons, it is highly unlikely that the power output of a nuclear plant would be changed frequently. In fact, Exelon Nuclear runs its nuclear units at full output even when spot energy prices are below the incremental costs of running the units.

- **The economic withholding the draft report assumes is also unrealistic**

The draft suggests that Exelon Nuclear, Midwest Generation and Ameren might benefit from bidding up base-load generation on peak days for a few hours to increase profitability. The draft finds that such economic withholding would only be profitable if Exelon Nuclear or Midwest Generation bid up their entire portfolios for peak hours on peak days. (Draft at 125, 163.) To the extent that the authors are suggesting that this would be a feasible strategy to exercise market power, the draft is clearly erroneous. It is not clear, however, that the draft really does conclude such bidding behavior would be feasible. The draft correctly notes that if such bidding were implemented, the resulting unit dispatch might well be infeasible for coal and nuclear units – that is, for the generating plants owned by Exelon Nuclear and Midwest Generation. (Draft at 125.) In this, the draft is correct – Exelon Nuclear and Midwest Generation units could not in fact implement such bidding, as explained further below.

To the extent that the draft is suggesting Exelon Generation and Midwest Generation could increase their profits by bidding up prices, the draft relies on assumptions that ignore real-world market behavior. In the first place, the most profitable strategy identified in the draft is not possible under PJM market rules. The draft concludes that it would be far more profitable to enter high bids for only the peak hours on peak days, rather than for the whole day. (Draft at 125, 163.) In fact, however, PJM's bidding procedures require that bids in the day-ahead market be the same for all 24 hours of the day.[1] This means that a unit could not be bid at a high off-peak price in the day-ahead market to partially withhold it from the market, while bidding a lower on-peak price to maintain maximum on-peak dispatch levels.

More generally, the economic withholding assumption ignores bidding behavior exhibited in organized power markets. In the PJM and Midwest ISO markets, load-serving entities (LSEs) bid load into the market, just as generators bid in generation. The authors assume that the load bid into the market every day is constant, giving generators a fixed load target on which to base withholding strategies. The reality, however, is that the LSEs can adjust the demand they bid into the day-ahead market in response to any strategy of high bidding by generators. Because there is sufficient generating capacity to serve the actual load in the real-time market, any reduction in demand could result in the high bids of the base-load generation in the day-ahead market not being accepted. This would place the nuclear units in the same situation as physical withholding, and the above considerations show why any form of withholding is impracticable for these units. In actuality, the nuclear units are price-takers in the PJM market; Exelon Nuclear bids the units into the day-ahead market at "zero," meaning that it will take whatever the clearing price is. The unattractiveness of economic withholding is a major reason why base-load generating units seek relatively long-term bilateral contracts to assure their continuous operation per their design specifications. A major weakness of the draft's market analysis is that it leaves the bilateral markets out of account; the authors recommend this for further study. (Draft at 168.)

The assumptions of the draft about economic withholding also ignore existing PJM automatic bid caps, discussed below, which would prevent the high bids the draft hypothesizes. They also ignore the MMU surveillance of price-cost markups and unusual bidding behavior, also discussed below.

- **The draft does not consider PJM's imposed bid caps**

The prerequisite for any withholding strategy to succeed in a large interstate market like PJM is that there be local transmission constraints that limit the availability of substitute power. ComEd demonstrates below that the draft's conclusions about transmission congestion in northern Illinois are based on faulty and outdated data and are invalid. In addition, however, even assuming that the congestion hypothesized by the draft existed, the authors completely ignore the PJM market mechanism in place for preventing market power when such congestion exists.

If northern Illinois became transmission-constrained, automatic PJM market power mitigation measures would likely be triggered. When an area within PJM becomes constrained, PJM automatically imposes caps on bids when there are less than three pivotal suppliers in the constrained area. Given the size of the generation fleets owned by Exelon Generation and Midwest Generation in northern Illinois, if that area became

[1] The PJM eMarket User Guide states "only one price-based schedule can be made available in both the day-ahead market and in the balancing market." www.pjm.com/etools/downdoads/emkt/ts-userguide.pdf.

constrained the three-pivotal-supplier test would generally be failed. In that case, where congestion is detected in the day-ahead market, PJM will cap all bids into the market at marginal cost plus 10 percent, so that locational marginal price (LMP) could not be set by bids that reflected potential exercise of market power. The only profitable economic withholding strategies identified in the draft involve bids many times higher than the level that the PJM market rules would allow. In particular, the draft concludes that economic withholding is profitable for Exelon Nuclear only if bids for the entire fleet are increased by more than 20-fold over production costs. (Draft at 163.) Thus the draft report hypothesizes that LMP will rise when there is congestion and concludes that generators could exercise market power under such conditions, but this conclusion results simply from the fact that the draft did not consider actual PJM market mechanisms and operations.

- **The draft ignores the role of the PJM Market Monitor**

Because the draft does not take into account the structure and rules of the PJM market, it ignores the crucial role that the PJM Market Monitoring Unit (MMU) plays in preventing any exercise of market power in the PJM markets. The draft concedes in general that "[a]ll markets have installed monitoring mechanisms that, in one form or another, require generation companies to justify taking units out of service, particularly during peak load periods." (Draft at 104.) Yet the authors take no account of the PJM MMU in considering the viability of withholding to increase profits. The MMU has a professional staff that continuously monitors the operation of the PJM real-time and day-ahead markets, as well as the bilateral market. The MMU determines congestion costs and the ability of any market participant to exercise market power within PJM. Generators are required to provide detailed cost information to the MMU, including fuel costs. The MMU has developed models to compare actual prices and bids to those it would expect under given conditions, and screens designed to detect unusual price results or bidding patterns. The MMU examines price-cost markups as part of its normal course of evaluating market conditions and market power.

When the MMU detects anomalies, it has informal discussions with the market participant, and MMU representatives have frequently stated that this step is very effective. If such discussions do not satisfy the MMU, however, it can issue Demand Letters that are automatically sent to the FERC, the Department of Justice, the Federal Trade Commission and the state regulatory commission, and it may file complaints with any of those bodies. In total, these measures are extremely effective in disciplining bidding behavior in the PJM markets. If Exelon Generation is contemplating a change in its bidding or other behavior that it believes is appropriate but that might fall outside one of the MMU's screens, Exelon Generation engages in discussions with the MMU to assure that the MMU is comfortable with the anticipated change before implementing it.

- **The draft's bid assumptions are unrealistic**

Even if the draft did not ignore all the PJM market structures and rules that make its assumptions about withholding generation to drive up prices either highly unlikely or impossible, errors in the more detailed assumptions the authors have incorporated in the model make the conclusions untenable. For example, even if withholding could be undertaken profitably – contrary to all the facts shown above – the profitability the draft calculates is exaggerated because of unreasonable bid parameters. The authors ran "Production Cost" models to determine whether withholding generation could be profitable. They used two alternative sets of assumptions about bidding, "Case Study Assumptions" and "Conservative Assumptions." The Case Study Assumptions are the base case assumed by the authors in determining the profitability of withholding strategies. These Case Study Assumptions, however, are unrealistic.

For the Case Study Assumptions, the draft assumes that the prices at which generating units are bid into the market incorporate fixed operating and maintenance costs. (Draft at 47.) But the assumption that unit bids routinely include fixed costs is neither theoretically sound nor supported by actual bid data and can result in poor modeling of unit commitment and dispatch. Economists typically model offers at variable cost, or at some increment higher than variable cost to reflect such costs as startup costs. The alternative Conservative Assumptions, under which fixed O&M costs are not included in the bids, are much more realistic.[2] Unfortunately, the draft contains only limited results for the Conservative Assumptions. When both cases are reported, however, the draft finds far less profitability under the Conservative Assumptions than under the Case Study Assumptions. Even if withholding were feasible – which it is not – the draft thus exaggerates its profitability.

- **The draft's HHI analysis is invalid**

The HHI is a mathematical measure that summarizes in a single value the degree of market concentration on a static basis. It is calculated by summing the squares of the market participants' market shares. The HHI takes into account the relative size and number of firms in a market. Markets with an HHI of less than 1000 are labeled "unconcentrated", markets with an HHI of 1000 to 1800 are labeled "moderately concentrated", and markets with an HHI of more than 1800 are labeled "highly concentrated". HHIs do not themselves indicate the exercise of, or even the ability to exercise, market power, but merely provide a measure of the concentration in a market. The draft report calculates an HHI of 1,123 for Illinois in 2007, which would fall in the lower end of a moderately concentrated market. (*See* Table 2.3-1 for 2001 and Table 3.5-1 for 2007.)

The draft's HHI analysis, however, is erroneous. The U.S. Department of Justice and Federal Trade Commission *Horizontal Merger Guidelines*, which set the HHI as the standard for measuring market concentration in market power analyses, are very clear that the first step in calculating an HHI is the determination of the relevant geographic

[2] A unit commitment algorithm was used for the Case Study Assumption, but not for the Conservative Assumptions, where all units were assumed to be on line. ComEd does not have access to this algorithm, but including fixed costs in the model can cause the predicted unit commitment to vary significantly from what it would be in reality.

market. (*Guidelines*, Section 1.21.) The draft makes no attempt to determine a relevant geographic market. It assumes, in effect, that the political boundaries of the State of Illinois define a relevant geographic market for electricity, presumably because those political boundaries define the jurisdiction of the ICC, which commissioned the analysis. Extensive evidence, however, demonstrates that Illinois is not a relevant geographic market for electricity. In particular, the rebuttal testimony of Dr. William H. Hieronymus, ComEd Exhibit 15.0 in ICC Docket No. 05-0159, demonstrates that northern Illinois, which is integrated into the interstate PJM market, has very high price commonality with the broad area to its east extending all the way to the Allegheny Mountains. In an empirical analysis based on the GE MAPS model, ComEd prices were essentially identical with those at buses in Northern Indiana Public Service, the lower peninsula of Michigan, American Electric Power, Dayton Power & Light, Cinergy and the Ohio portion of First Energy. Much of the time, they were also identical to prices in MidAmerican Energy, Louisville Gas & Electric and Illinois Power. Thus at a minimum the relevant geographic market should include a large portion of PJM and of MISO south and east of Illinois.

With the addition of even a small portion of this generating capacity – and the draft does not attempt to include *any* imports into Illinois in its HHI calculation – the HHI concentration measure will fall from the draft report's 1,123 to less than 1,000, which would put the HHI for the relevant market in the unconcentrated range.

Conclusion on markets

Markets for electricity relevant to Illinois have changed so significantly since the model on which the draft relies was developed that no conclusions about markets can be drawn from the document. The analysis of market concentration is clearly inconsistent with the current facts of regional market operation. Just as clearly, the scenarios that the draft finds could lead to the exercise of market power in Illinois range from unrealistic to impossible under existing market structures, market rules and market monitoring and mitigation.

B. The Draft's Transmission System Analysis Is Based on Faulty Assumptions

The draft finds that the transmission system in Illinois, and especially northern Illinois, will be constrained in 2007, setting the stage for the authors' findings that congestion on the system will facilitate the exercise of market power. Much of the congestion predicted by the draft for northern Illinois is erroneous or has been addressed by already installed or pending transmission reinforcements. ComEd cannot analyze the source of the errors in detail without access to the underlying inputs and workpapers for the draft. The conclusions, however, are simply not consistent with either the existing system or with the planned future system, and ComEd can point to some of the problems that clearly underlie the invalidity of the draft's analysis.

- **The draft ignores transmission reinforcements**

The draft is based on the 2003 Summer Case prepared by NERC in November 2002, with certain inputs from the utilities as to future plans. (App. E at E-3.) The authors admit that "no new transmission resources were added to the system" for purposes of their analysis, yet they attempt to draw conclusions about system congestion in 2007. (Draft at 168.) These conclusions are entirely vitiated by the use of inadequate and outdated data and by the fact that the authors do not appear to recognize the limitations of the data. The NERC 2003 case is now outdated; the authors concede that transmission reinforcements have already been constructed in Chicago that are not reflected in the NERC data or their analysis. (Draft at 51n.14.) Whatever updated studies the authors obtained from the utilities in 2003 are by now outdated as well. Moreover, transmission studies using future system models are performed by utilities and RTOs for the specific purpose of determining where constraints are likely to develop on the system so they can be relieved by system reinforcements. Any projected system constraints obtained by the authors from the utilities in 2003 became the starting point for the utilities' system expansion plans. Thus, even assuming that there have been no changes in the model since the 2003 update, what the draft report takes as evidence of future transmission constraints is in fact the blueprint for future transmission expansion to prevent those constraints from developing, if in fact relieving those constraints is economical[3].

Perhaps even more damaging to any long-term conclusions, the draft report again completely leaves PJM out of account. PJM has system planning responsibility for the entire multi-state PJM area, including northern Illinois. Every year, PJM conducts load deliverability tests to identify transmission system reinforcements needed to meet reliability criteria, and PJM also has a process in place to address economic upgrades to the system. Those reinforcements are then incorporated in the baseline of the PJM Regional Transmission Expansion Plan, which the transmission owners in PJM, including ComEd in northern Illinois, are required to build. Because the draft takes no account of planned reinforcements to the system, its projections of system operation in 2007 are invalid and the congestion that the authors predict for northern Illinois is simply an artifact of their use of inadequate data. Similar MISO planning processes are also not addressed.

- **The authors added future generation without the necessary transmission**

The draft is even more biased towards finding future transmission constraints than the above would indicate. In modeling the future system, the authors included all generation that Independent Power Producers (IPPs) have expressed an intention of building, but have included *none* of the transmission reinforcements necessary to support the new generation. The draft ignores the fact that PJM performs generation deliverability tests for all new generating units that will be capacity resources – which includes nearly all IPP generation in northern Illinois – to assure that the units' outputs can be delivered to

[3] It is not always economical to relieve constraints by expanding the transmission system. The cost of expanding the transmission system must be compared to the savings in congestion charges.

the system. The deliverability study identifies all system reinforcements that would not be necessary but for the interconnection of the new generating unit. These "but for" transmission reinforcements are constructed before the new generation is interconnected to the system. Adding generation without adding any system reinforcements, as the draft does, is virtually guaranteed to create phantom congestion on the transmission system.

- **The predicted constraints for northern Illinois are invalid**

ComEd has examined the transmission constraints predicted on the ComEd system for 2007. Some of the predicted overloads simply were not valid. For example, the draft asserts that a 345 kV line on the ComEd system (the Cordova 345 kV, which connects the Cordova IPP bus to the ComEd Cordova bus) will be constrained for 2300 hours per year. (Draft at 50.) ComEd has in fact experienced no congestion at all on this line and does not project any congestion on the line for at least ten years. The draft also frequently mentions the Mazon-Oglesby line as constrained. It is true that a directional relay limits this line to 115 MVA, but that is in the direction *leaving* Mazon, while the flow on the line is typically *into* Mazon, so that the limit does not apply. Current system studies do not show constraints on this line.

In other cases, overloads found by the draft were potentially valid, but ComEd already knew about them and either they have been addressed by transmission reinforcements already or will be addressed by reinforcements being planned for the future before the constraints are realized. Significant examples include the following constraints shown on Table 4.1.2-1 of the draft (referencing the artificial designations the authors have used for portions of the ComEd transmission system.)[4]

- Overloads in the NI-B zone were addressed by the installation of an autotransformer at Pleasant Valley substation in 2005.
- Overloads in the NI-C zone were addressed by the installation of an inductor in 138 KV line 0906 in 2004.
- Overloads in the NI-D zone will be addressed by the installation of the West Loop 345 kV project in 2008. Current system studies do not show constraints prior to that time.
- Overloads in the NI-E zone from East Frankfort to Goodings Grove will be addressed by the installation of an autotransformer at East Frankfort in 2006.

- **The authors attempted to model system operation without following the actual system operating steps**

The authors indicate that their analysis did not take into account operating steps that might be taken by an ISO to relieve congestion. (Draft at 50.) The use of such operating steps, however, is an important and accepted practice in PJM (and was an accepted practice at ComEd prior to its integration into PJM) to mitigate constraints or

[4] ComEd does not agree that there is any validity to the authors' division of the ComEd system into various zones.

overloads. Significant examples of operating steps mitigating constraints found by the draft include the following:

- Overloads found by the draft on LaSalle – Mazon for loss of 345 kV line 1223 (App. F, Table F.1-1) are relieved by closing the Dresden 138 kV bus line.
- Overloads on Hanover Park – Spaulding and the Wayne autotransformer for loss of 345 kV line 14402 are relieved by closing the 345 kV bus tie at Wayne.
- For many of the contingencies in Chicago, bus ties are closed post-contingency and phase shifters are adjusted to bring loadings back to within applicable limits.

Conclusion on transmission congestion

The draft does not take account of the fact that when system studies predict constraints, transmission planners proceed to deal with the predicted conditions in accord with system criteria. Furthermore, the draft admittedly does not take into account operator actions to relieve congestion. In addition, the data on which the authors base their conclusions about transmission congestion in Illinois are now several years out of date, and the draft is thus based on a model from which no valid conclusions can be drawn about system congestion in 2007 and thereafter.

In sum, as with any engineering or economic study of this nature, it is critical that analyses be based on relevant and timely data and that any conclusions drawn be carefully crafted to account for all the parameters that, in the real world, will govern participants' incentives and actions. Hre, due largely to unfortunate budget limitations beyond Staff's control, both the data and many of the analytical assumptions are obsolete. Moreover, a number of the conclusions drawn from that analysis simply fail to take account of important physical, economic and regulatory factors. As a result, the Commission can draw no valid conclusions from this draft document about either transmission constraints or market behavior in 2007 or beyond.